SOUTHERN AFRICA ENERGY PROGRAM

ZESCO TRANSMISSION PRICING

WORKING REPORT 1: REVIEW OF DOCUMENTATION AND IMPLICATIONS FOR ZESCO TRANSMISSION PRICING

Outcome 2, Intervention Y3.02.03.05 ZMB

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ABBREVIATIONS

Abbreviation	Full Text
AER	Australian Energy Regulator
AER	Australian Energy Regulator
ANEM	Australian National Electricity Market
APF	Average Participation Factor
CAIDI	Customer Average Interruption Duration Index
CESS	Capital Efficiency Sharing Scheme
COSS	Cost of Service Study
CPI	Consumer Price Index
CRNP	Cost Reflective Network Pricing
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ECOWAS	Economic Community of West African States
Egenco	Electricity Generation Company Malawi Limited
ENTSO-E	European Network of Transmission System Operators for Electricity
ERB	Zambian Energy Regulatory Board
ESCOM	Electric Supply Commission of Malawi
FERC	Federal Energy Regulatory Commission
HVDC	High Voltage Direct Current
LRMC	Long-run Marginal Cost
MAIFI	Momentary Average Interruption Frequency Index (
MAR	Maximum Allowable Revenue
MERA	Malawi Energy Regulatory Authority
MISO	Midcontinent Independent System Operator
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NERSA	National Energy Regulator of South Africa
NGET	National Grid Electricity Transmission PLC
OAR	Open Access Regime
Ofgem	UK Office of Gas and Electricity Markets
OVF	Offer Volume Forecast
PJM	A US regional transmission organization (Pennsylvania, Jersey, Maryland)
PPL	Power Planning Associates, a UK consulting firm.
PSS/E	Power System Simulator for Engineering. A tool for simulating power grid behaviour.

PTDF	Power Transfer Distribution Factor
PTRM	Post-tax Revenue Model
RA	Revenue Allocation
RAB	Regulatory Asset Base
RERA	Regional Electricity Regulators Association of Southern Africa
RR	Revenue Requirement
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPP	Southern African Power Pool
SAPP CC	SAPP Coordination Centre
SRMC	Short-run Marginal Cost
STPIS	Service Target Performance Incentive Scheme
THN	Transit horizontal network
TK	Transit Key
TNSP	Transmission Network Service Provider
TSO	Transmission System Operator
TUOS	Transmission Use of System
vRES	Variable Renewable Energy Source
WACC	Weighted Average Cost of Capital

1. INTRODUCTION

With a view towards addressing the constraints of low commercial viability of ZESCO and limited regional harmonization and cross border electricity trade, ZESCO has requested SAEP to provide advice and assistance to establish a robust approach to transmission pricing and charging of wheeling services.

As part of this study, relevant documents from key utilities and regulators in the region, and from several international organizations, have been collected and reviewed to identify common approaches to transmission pricing.

The scope of the current work on developing prices for ZESCO is limited to transmission pricing, and does not address the pricing of ancillary services, the procurement of which will make up the bulk of the System Operator's costs. This review therefore does not consider documentation or practices specific to ancillary service pricing.

1.1 STRUCTURE OF THIS REPORT

This report is structured in two parts: firstly a description of documents on the basis for, and application of, transmission pricing in different jurisdictions nationally, regionally and internationally, and secondly, the results of an analysis of these documents to identify standard methodologies for transmission pricing, data requirements to implement them, and issues identified their application.

In the first part, a brief description of each document is provided, and a discussion of the elements of interest or significance. A table setting out the system parameters (peak load, network size, customer base) is presented to give some context for the different utilities or system operators discussed. The documents identified have been categorized for evaluation as follows:

- Zambia specific – context and requirements (section 2).
- SAPP wheeling – precedent and consistency (section 3).
- International – common practice and issues.
  - Regional (section 4)
  - Australia and New Zealand (sections 5.1 & 5.2)
  - USA (section 5.3)
- General & Technical – general background and theoretical understanding (section 6).

Drawing from the specific document reviews summarized in the first part, the second part sets out a comparative analysis of the approach described in the documentation, differentiating between transmission generally (section 7.2) and use-of-system (wheeling) pricing (section 7.3).

1.2 ACCESS TO DOCUMENTS

As proposed in the Inception Report, a separate file directory has been established at ZESCO and copies of all documents reviewed below have been placed in the directory for access by ZESCO staff.

Copies of all documents are also available from SAEP.

2. ZAMBIAN DOCUMENTATION

2.1 DOCUMENTS CONSULTED

Documents were obtained in respect of the following related areas:

- Zambia Legislation.
- The Zambian Transmission Grid Code.
- The development of an open access regime for Zambia.
- The Cost of Service Study being conducted for the ERB.
- The Res4Africa study on renewable energy integration into the Zambian grid.

2.1.1 ZAMBIAN LEGISLATION

Document 2-1

Title	Electricity Act, 2019		
Author	Zambian Government	*Date*	2019
Comment	The electricity sector is Zambia is legislated in terms of the Electricity Act, 2019, which replaced the Electricity Act, 1995. The Act defines the entities requiring licences, establishing the roles of Transmission Network Service Provide (TNSP) and System Operator (SO). The Act envisages an open access regime, which has been described in draft Open Access Regime (OAR) regulations. The Minister is now expected to issue a statutory instrument operationalizing the OAR. It should be noted that the Act defines "open" access as access to the availability of spare transmission capacity".		

2.1.2 ZAMBIAN GRID CODE

Document 2-2

Title	Zambian Transmission Grid Code		
Author	Zambian Energy Regulatory Board	*Date*	current
Comment	The Grid Code comprises five chapters: Governance, Network, Metering, System Operations, and Information Exchange. The Network chapter does not contain any stipulation on how costs of the transmission grid should be recovered. It does specify the planning process for transmission grid development, with such planning to be done on a five year-ahead basis. The Code stipulates the economic criteria to be used for determining whether new investments are justified. The System Operations chapter establishes the services which the System Operator must provide.		

Document 2-3

Title	ZESCO System Operator Licence		
Author	Zambian Energy Regulatory Board	*Date*	Oct 2016
Comment	The licence specifies the obligations of the System Operator as (*inter ales*) to: o Ensure a safe, secure, reliable, economical and efficient operation of the transmission system. o Operate the system so as to match supply and demand in real time. o manage constraints on the Transmission System through the determination of operational		

	limits and the purchase of ancillary services where applicable. ○ coordinate the long-term ability of the transmission system to meet current and future demand for the transmission of electricity and contribute to the security of supply through adequate planning and operation of the transmission capacity and system reliability ○ The Licensee shall procure such assets and services and such quantities and types of ancillary services which are necessary to carry out its functions in accordance with the Grid Code and the SAPP

The licence does not provide any guidance as to the form any charge for system operations should take, just that it needs to be approved by the ERB:

> "*The Licensee shall submit to the ERB the proposed method of calculating its proposed charges, and it shall provide to the ERB any other information as the ERB may require in its consideration of the Licensee's application in the format as may be specified by the ERB.*"

2.1.3 ENERGY REGULATORY BOARD OPEN ACCESS

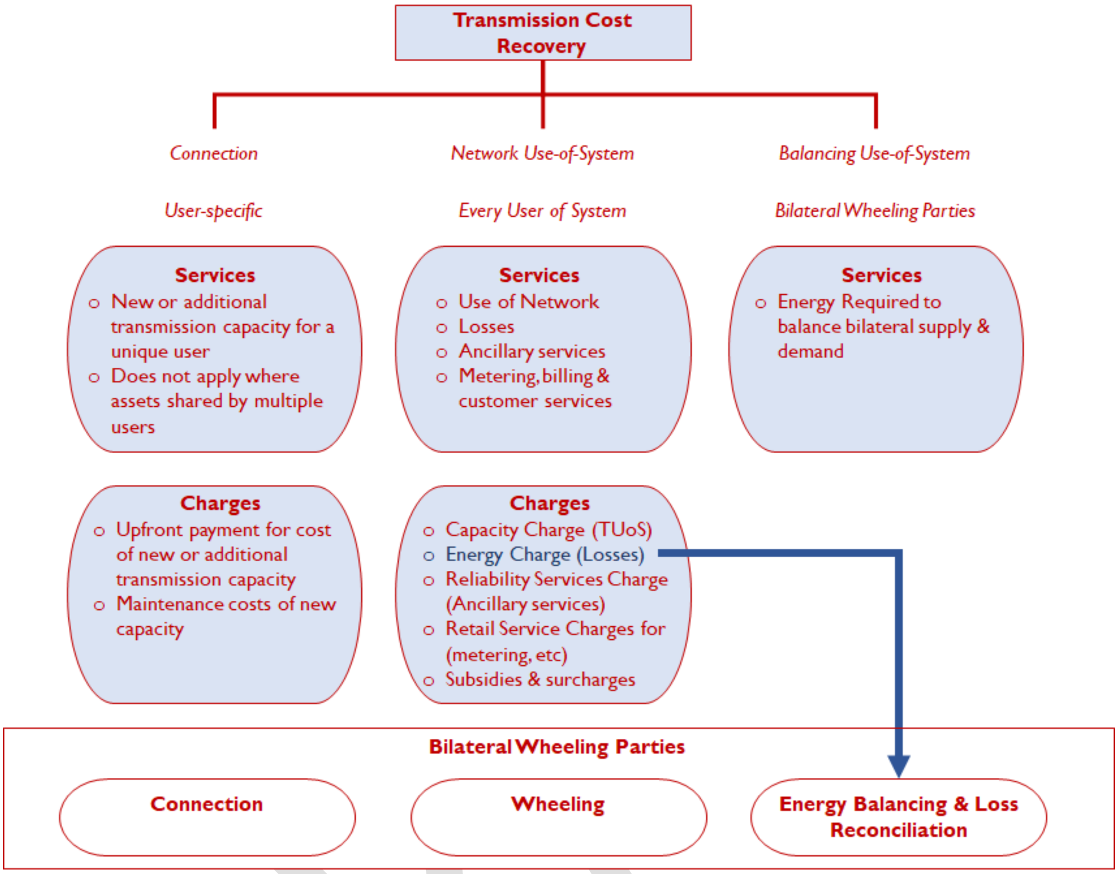
A set of open access regulations has been established in the form of a draft statutory instrument in terms of the Electricity Act, but this has not been put into effect. In 2017 the ERB proposed an interim transmission pricing regime to apply to parties wheeling on the Zambian network.

Document 2-4

Title	Proposed Interim Third-Party Transmission/Distribution Use-of-System Charging Methodology		
Author	Energy Regulatory Board	*Date*	Nov 2017
Comment	This document was a 'Management Paper' proposing a methodology and rate for wheeling transactions. The paper did not differentiate between ZESCO's TNSP and SO functions. The paper identified the principles for allocating costs between the two TNSPs in Zambia, ZESCO and CEC. The SAPP definition of Wheeling was proposed: "*transmitting a contractual amount of power over specified time periods through the system of a [TNSP] who is neither the Seller nor the Buyer of this power*".		

The generic components of transmission pricing and the proposed structure of cost allocation to wheeling third parties developed in the paper is illustrated in Figure 1 below.

Figure 1: ERB Transmission Pricing Structure



Although the description in the paper does not differentiate between TNSP and SO, the separation of use-of-system and quality charges in the formula enables differentiation between their respective charges.

The ERB proposed that the wheeling charge take the form of a MW-km[1] rate, noting the method's disadvantage of the lack of a relationship between the geographical distance and the actual transmission facilities involved in a transaction. A basic $/kWh charge is proposed as an interim measure, calculated as the Annual Revenue Requirement (RR) divided by the annual energy flow over the network.

The paper then proposes a confused[2] wheeling charge structure to allocate wheeling costs across ZESCO and CEC networks, whereby each TNSP's share is given by the following formula:

Wheeling Charge = Revenue Requirement/Total Wheeled Power
x ∑(Number of Lines Used x Distance x Share of Wheeled Power)
+ Quality Charge

where:

- Revenue Requirement (RR) is determined as O&M expenses + Rate Base x Rate of Return.

[1] The paper proposes MW-mile, but ZESCO comments that this should be MW-km in the Zambian context.

[2] As presented, the formula's units do not balance. The formula as presented supposedly produces a $/kWh charge derived from an aggregate distance. It also implies that a single wheeling transaction across both networks would involve different amounts of energy.

- Total Wheeled Power is the total wheeled for each transaction.
- Share of Wheeled Power is the amount of each transaction wheeled by the specific TNSP.
- Number of Lines (L) is the number of lines used for the wheeling transaction
- Distance (D) if the distance between entry and exit points for the wheeling transaction.
- Quality Charge is the charge to recover costs of reliability & ancillary services.

The formula as presented is incorrect as it results in units for the use-of-system component of:

($/MW) x (unitless number x km x MW) = $-km.

It is assumed that what is proposed is a distance-based MW-km approach, and the formula would include a denominator setting out total system capacity and km of lines. It is not clear whether the paper proposes the use of power flows modelling to determine utilisation of lines.

Energy balancing and losses reconciliations are to be settled by the SO through metering and billing arrangements at the end of each settlement period, with deficits to be paid by the party out of balance.

The ERB continues to take advice on the most appropriate form for the open access regulations, most recently through a 2019 peer review carried out by the US National Association of Regulatory Utility Commissioners (NARUC).

Document 2-5

Title	The Electricity Open Access Regulations, 2015 – draft Statutory Instrument		
Author	Energy Regulatory Board	*Date*	2015
Comment	The draft regulations envisage a use-of-system charge in the form of a postage stamp Zambian currency rate per kWh. The rate would be recovered from "open access users", which are identified in a schedule as generators, end users, distributors and transmission service providers.		

The following documents and presentations were presented as part of a workshop run by the ERB in May 2019 presenting results of the NARUC review.

Document 2-6

Title	Zambia's Power Sector Regulatory Framework Overview (Presentation)		
Author	Energy Regulatory Board	*Date*	May 2019
Comment	A general overview of the Zambian power sector and the ERB's role in it.		

Document 2-7

Title	Proposed Open Access Regulations (Presentation)		
Author	Energy Regulatory Board	*Date*	May 2019
Comment	General overview of the ERB's draft Open Access regime for Zambia. The regime provides for the collection and disbursement of various charges relating to the use of the transmission system (including application fees, use of system charges and the scheduling and system operator charges)		

Document 2-8

Title	Peer Review of Grid Code		
Author	National Association of Regulatory Utility Commissioners (Arizona)	*Date*	May 2019
Comment	A set of review comments on the specific wording in the Grid Code. Comments on need for a more robust way of determining transmission line requirements for interconnecting at 1000 MW are noted.		

Document 2-9

Title	Peer Review of proposed Licence Conditions		
Author	National Association of Regulatory Utility Commissioners (PJM)	*Date*	May 2019
Comment	Of particular interest is the comment "*To avoid the inevitable disputes to come, I recommended more specificity and transparency around the calculation of 'spare capacity', the amount of capacity reserved 'for system security' … and reliable transparent and timely information for others who must rely on that transmission capability in order to finance and operate new needed independent generation projects in Zambia*."		

Document 2-10

Title	Peer Review of the Draft Open Access Regime - Highlights		
Author	National Association of Regulatory Utility Commissioners	*Date*	May 2019
Comment	The highlighted issues relate to the need for an independent ISO and the need to prepare for larger vRES integration into the grid.		

2.1.4 COST OF SERVICE STUDY

The following documents were reviewed.

Document 2-11

Title	Zambia COSS Final Load Forecast Report		
Author	Economic Consulting Associates	*Date*	18 May 2018
Comment	This was the only deliverable from the initial, abortive CoSS. It developed a detailed independent load forecast that was not subsequently adopted by ZESCO. It provides a cross-check on input assumptions.		

Document 2-12

Title	Zambia Cost of Service Study Inception Report		
Author	Energy Market and Regulatory Consultants Limited	*Date*	Jan 2020
Comment	The COSS outcome is intended to be a methodology that will allocate the allowed revenues amongst the various customer groups or tariff categories based on sound economic principles. This report sets out the approach and some of the input assumptions to be used in the COSS. The data from this report and subsequently developed through the COSS will be used where required in ZESCO's transmission pricing modelling. The PSS/E cases to be used in the COSS are the same as used for the Res4Africa study. The COSS will provide the base-line costs that will be acceptable to the regulator for use in the transmission pricing.		

2.1.5 MINISTRY OF ENERGY RES4AFRICA STUDY

Document 2-13

Title	Integration of Variable Renewable Energy Sources in the National Electric System of Zambia Final Report		
Author	Res4Africa	*Date*	Feb 2020
Comment	The study identifies maximum levels of vRES that can be integrated into the Zambian grid, levels of reserve required, and minor grid reinforcements required. The key conclusion in respect of transmission pricing is that the existing grid and planned reinforcements can support the levels of vRES proposed. A separate detailed review of this report has been prepared.		

3. SAPP DOCUMENTATION

This section also provides an historical perspective of the development of wheeling charging methodology in the Southern African Power Pool (SAPP).

3.1 Documents Consulted

Document 3-1

Title	SAPP Transmission Pricing Model Development and Implementation Final Report		
Author	AF Mercados	*Date*	Sep 2014
Comment	The report describes the methodology finally adopted following discussion with SAPP and the results obtained by applying the methodology to the SAPP transmission system. It compiles all the information developed as part of the project. The methodology and proposals are summarised below		

Document 3-2

Title	A methodology for deriving Transmission Network Charges for wheeling in the Southern African Power Pool (Tutorial presentation)		
Author	SAPP Transmission Pricing Task Team	*Date*	August 2015
Comment	Description of the Power Transfer Distribution (PTDF) and Average Participation Factor (APF) pricing methodology		

Document 3-3

Title	Summary of SAPP Transmission Pricing Model Development and Implementation		
Author	SAPP Coordination Committee	*Date*	Aug 2015
Comment	The report highlights the financial impact of the proposed methodology on utilities by comparing the 2014 wheeling charges under the current methodology with those calculated using the proposed pricing model. The report a high-level description of the base assumptions in the model.		

Document 3-4

Title	SAPP Transmission Pricing Model Assumptions		
Author	SAPP Transmission Pricing Task Team	*Date*	Aug 2015
Comment	The report sets out the replacement costs of assets (lines, transformers, unit bays, capacitor banks) assumed in the SAPP model. More recent values of these may now be available but this provides a dataset that can be used for modelling the transmission pricing methodology adopted by ZESCO.		

Document 3-5

Title	Scope of Work for Transmission Pricing Implementation in SAPP		
Author	SAPP Coordination Committee	*Date*	Oct 2016
Comment	Evidence of the state of development of the pricing model at that time.		

Document 3-6

Title	SAPP Transmission Pricing Model (Presentation)		
Author	ZESCO (internal presentation)	*Date*	May 2018
Comment	Useful summary of entry-exit methods (average participation, marginal participation, PTDF, hybrids) and description of SAPP model.		

3.2 EVOLUTION OF SAPP WHEELING CHARGES

3.2.1 PRE-1999 WHEELING METHODOLOGY

The original methodology adopted by SAPP (used before 1999) for wheeling charges was a postage stamp charge based on the number of transit countries involved in wheeling the power. The wheeling tariff was based on 7.5% of the value of the energy transferred in case the power was wheeled through one transit country and 15% of the value of the power transferred was wheeled through more than one country.

A key characteristic of this methodology is that the counterparties to each trade had to be known.

3.2.2 WHEELING CHARGING APPROACH POST 1999

A new methodology was introduced from 1999 that was based on the calculation of a recoverable "rent" to be payable to the TNSPs. The rent was based on the MW-km (i.e. quantity injected, and the distance travelled) methodology. In this methodology (which uses the power simulation model), the proportion of the transmission asset of a transmission system owner (TSO) used for a specific trade was calculated. The entity responsible for the trade wheeled power paid to the TSO is also responsible for the "rent" payable to the TSO based on the proportion of the transmission asset used.

3.2.3 CURRENT METHODOLOGY

Around 2005/2006, as the SAPP was introducing the day-ahead power market, it was realised that counterparties to trades would not be specifically known (in terms of MW injected and distance travelled) and hence a change in methodology would be required to break their bilateral contract independence.

Therefore, around 2005/2006, SAPP appointed Power Planning Associates Limited (PPL[3]), a UK based engineering consulting firm, to develop a new methodology for the regional power market structure.

The methodology developed by PPL had the following two parts:

I. The determination of the network costs of wheeling and revenue shares per TNSP.

   This is calculated on the basis of the ratio of energy wheeled to the total energy transported on a defined transit horizontal network that represents all the assets that could be used for wheeling.

II. The determination of network wheeling prices to users/agents of the TNSPs' systems.

[3] Power Planning Associates preferred abbreviation, PPA, is not used as that abbreviation is too readily confused for Power Purchase Agreement.

A single nodal price ($/MW) for each country was determined and converted to energy prices ($/MWh) for each country. These prices, currently ranging from 0.004-0.7 USc/kWh are determined annually.

The methodology is described in more detail in section 7.3.2.

3.2.4 FUTURE METHODOLOGY

In 2013, SAPP commissioned AF Mercados to develop a wheeling charging methodology and model which could provide a more appropriate basis for the charging regime in the day ahead market regime.

AF Mercados proposed that inter-country compensation for use of the transmission network be computed based on the Marginal Participation method with multiple slack[4] nodes based on balanced transactions. The methodology is described in more detail in section 7.3.3.

Based on AF Mercados' work a new wheeling methodology and an associated pricing model was endorsed by the SAPP Executive Committee in April 2015. They were handed over to the SAPP Coordination Centre in July 2015 for implementation.

The initial implementation work included evaluating the financial impact of the new methodology on the various SAPP members.

The SAPP Pricing Model was used to calculate for each utility the payments to be made by Generators and Loads, and how these payments are distributed to the TNSPs and the modelling results using the proposed methodology were compared with the corresponding results using the existing methodology (*Document 3-3*).

The large differences between wheeling costs and revenues between the current and the proposed methods caused concern to SAPP members and further development work on the new method was proposed (*Document 3-5*). This work has yet to be completed.

[4] A slack (or swing) node is used in load flow studies to balance the active and reactive power in the system modelled. The slack node provides for system losses by emitting or absorbing active and/or reactive power to and from the system.

4. REGIONAL PRACTICE DOCUMENTATION

4.1 RERA

A number of documents have been prepared by Deloitte for the Regional Electricity Regulators Association of Southern Africa (RERA) as part of the Technical Support to develop a regional market framework funded by the United States Department of State through the Bureau of Energy Resources' Power Sector Program.

Document 4-1

Title	Transmission Pricing Methodology		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Sep 2018
Comment	A comprehensive summary of methodologies for transmission pricing and regional and international practice.		

Document 4-2

Title	Rules for Managing Congestion		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Sep 2018
Comment	A review of practice in Ireland, Nordic countries, the United Kingdom, and for merchant plant. Five methods of managing congestion are described: explicit auctioning, market splitting, implicit auctioning, counter trading, and re-dispatching.		

Document 4-3

Title	Dispatch and Curtailment Risk Guidelines		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Nov 2018
Comment	A description of the practice adopted by NERC and ENTSO-E, and proposed guidelines based on the review. The guidelines assume the establishment of transmission capacity rights with a compensatory mechanism when these rights are curtailed.		

Document 4-4

Title	Grid Code Framework		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Sep 2018
Comment	Sets out the proposed minimum technical requirements for cross-border interconnectors to support the reliability and security of the integrated power system. This covers technical standards, metering, data exchange, maintenance coordination and project coordination.		

Document 4-5

Title	Model Connection Agreement		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Jul 2018
Comment	The proposed clause 13 dealing with charging reads: a. … the Load or Generator shall pay the Transmission Company charges [to be specified in an Annex], any other charges, fees or amounts referred to in this Agreement and any other charge or fees they are permitted to charge by law or per SAPP obligation. b. The Load or Generator shall procure Control Area Services from a SAPP authorized		

	control area and pay the associated Control Area Service Charge. c. In addition to the above, all Loads, and Generators shall pay a SAPP system wide users fee to the SAPP CC. d. All the SAPP related charges shall be as detailed in the SAPP Agreement Between Operating Members or as negotiated bilaterally

Document 4-6

Title	Model Grid Interconnection Agreement		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Jul 2018
Comment	The clause 13 dealing with charging is similar to that in the Connection Agreement, but paragraph b reads: b. If one of the Transmission Companies does not have its own control area it shall procure this service from a SAPP authorized control area and pay the associated Control Area Service Charge.		

Document 4-7

Title	Model Grid Wheeling Agreement		
Author	Deloitte Financial Advisory Services, LLP	*Date*	Jul 2018
Comment	The wording is not consistent with the proposed pricing methodology but identifies the circumstances that need to be taken into account in pricing.		

4.2 South Africa

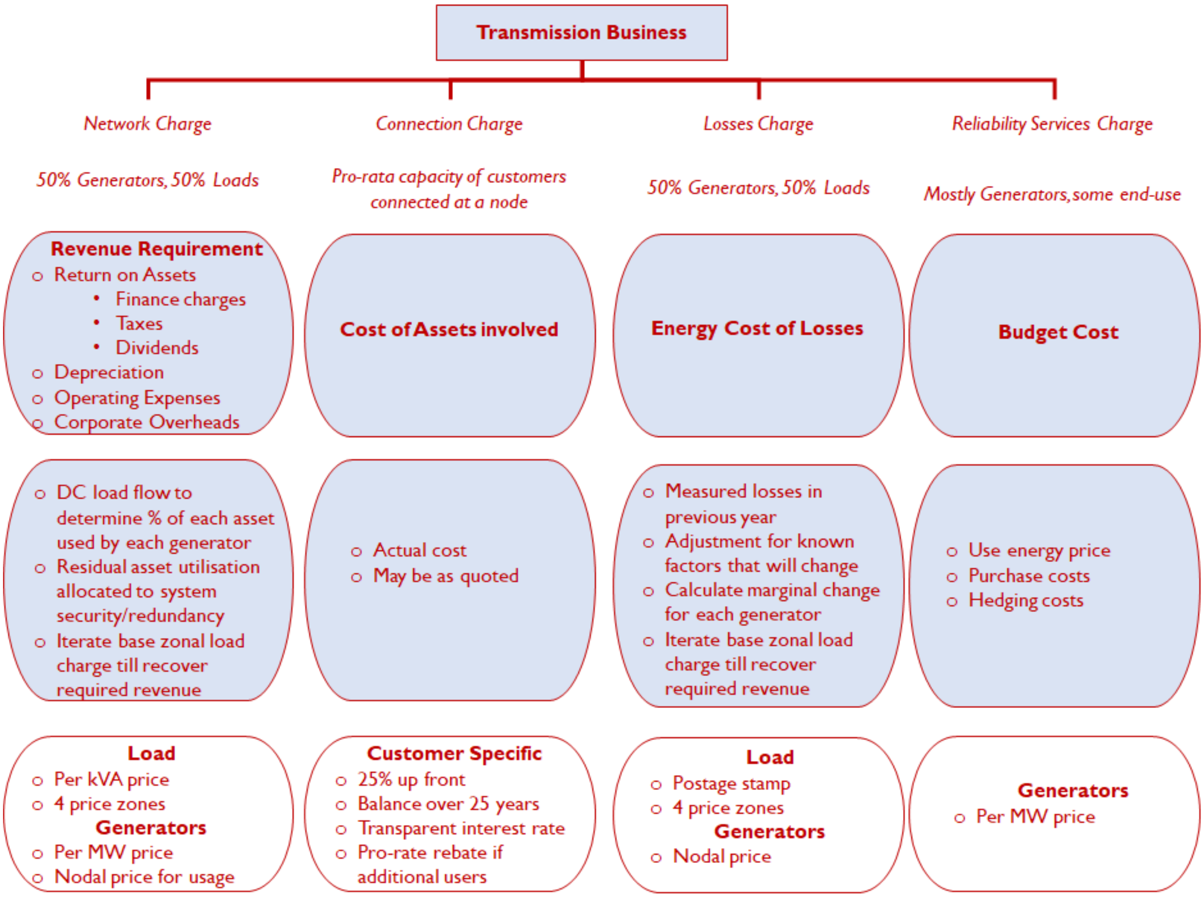
Electricity transmission in South Africa is dominated by the state-owned integrated utility ESKOM. The industry is regulated by the National Energy Regulator of South Africa (NERSA). NERSA publishes a Grid Code, and as part of this code, in 2018 published a draft transmission tariff code.

Document 4-8

Title	The South African Grid Code: The Transmission Tariff Code		
Author	NERSA	*Date*	Jul 2008
Comment	This code sets out the objectives of transmission service pricing and the procedure to be followed in applications to change revenue requirements or the tariff structure.		

The code establishes a structure for transmission tariff determination and allocation as illustrated in Figure 2.

Figure 2: South African Transmission Tariff structure



4.3 MALAWI

Transmission and distribution in Malawi are carried out by the Electric Supply Commission of Malawi (ESCOM), while generation facilities are owned and operated by the Electricity Generation Company Malawi Limited (Egenco).

Table 1: Escom/Egenco (Malawi) Metrics

Metric	Unit	Value
Installed Capacity	MW	363
Peak Demand	MW	350
Tx lines	km	2 395
Annual energy	GWh	1 320
Territory	Square km	118 480
Off-takers		325 000

The sector is regulated by Malawi Energy Regulatory Authority (MERA). In the lead-up to the restructuring of the Malawi market with the establishment of Egenco, MERA commissioned a study on recommended transmission tariff methodologies.

Document 4-9

Title	Malawi Power Market Restructuring Study: Task 3 Report: Tariff Methodology		
Author	AF Mercados	*Date*	Sep 2015
Comment	Proposes: ○ The Transmission System Allowed Revenue to be the sum of two components: the Base Allowed Revenue, and a Large Infrastructure Development allowance. ○ A four-year regulatory period. ○ The Transmission System Allowed Revenue is calculated based on a forecast firm cash flow discounted at the Allowed Rate of Return on Capital for the Tariff Period, considering: (a) Initial Regulatory Asset Base (the value of the assets belonging to the Licensee to provide the transmission service, excluding connection assets); (b) Rolling forward of the initial RAB, considering minor Capital Expenditure for the period. (c) Depreciation of existing non-depreciated assets. (d) Return on capital. (e) Efficient operational expenditure. (f) Taxes. ○ The transmission costs are recovered through a tariff based on dividing the required revenue by the peak MW adjusted by a forecast transmission loss factor.		

4.4 WEST AFRICA POWER POOL

Document 4-10

Title	Adoption of the Tariff Methodology for Regional Transmission Cost and Tariff		
Author	ECOWAS Regional Electricity Regulatory Authority	*Date*	Jul 2018
Comment	Covers the process for establishing which revenues are to be recovered and how they are to be allocated. Five steps are described: 1. Determine regional transmission assets and asset value 2. Calculate annual revenue requirements for each Transmission System Operator (TSO) asset used for regional bilateral trading 3. Calculate use of transmission system and associated transmission losses for each regional bilateral trade 4. Calculate transmission revenue requirements for each TSO for regional bilateral trades 5. Calculate transmission tariff and transmission losses for the purchaser of each regional bilateral trade		

5. INTERNATIONAL PRACTICE

5.1 AUSTRALIA

The market context for transmission pricing is established through the formulation of detailed Market Rules.

Document 5-1

Title	Market Rules Chapter 3 Market Rules		
Author	Australia National Electricity Market -	*Date*	Current
Comment	The Australian electricity market is a deregulated spot market based on the following principles: ○ minimisation of system operator decision-making to allow participants the greatest amount of commercial freedom to decide how they will operate in the market. ○ maximum level of market transparency in the interests of achieving a very high degree of market efficiency, ○ avoidance of any special treatment in respect of different technologies. ○ consistency between central dispatch and pricing. ○ equal access to the market for existing and prospective participants. ○ ancillary services should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis.		

Document 5-2

Title	Market Rules Chapter 6A Economic Regulation of Transmission Services		
Author	Australia National Electricity Market	*Date*	Current
Comment	There are detailed rules governing the determination of each element of the AER's transmission pricing structure. Included in this are four rules around the nature of the post-tax revenue model required to underpin transmission prices. 1. The NPV of the expected maximum allowed revenue for the provider for each regulatory year of the regulatory control period is equal to the NPV of the annual building block revenue requirement for the provider for each regulatory year. 2. The maximum allowed revenue in the first regulatory year is expressed as a dollar amount. 3. The maximum allowed revenue for each subsequent regulatory year is calculated by escalating the maximum allowed revenue for the previous regulatory year using a CPI - X methodology. 4. The total revenue cap for a regulatory control period is calculated as the sum of the maximum allowed revenues for each regulatory year.		

Two aspects of transmission pricing in Australia were considered:

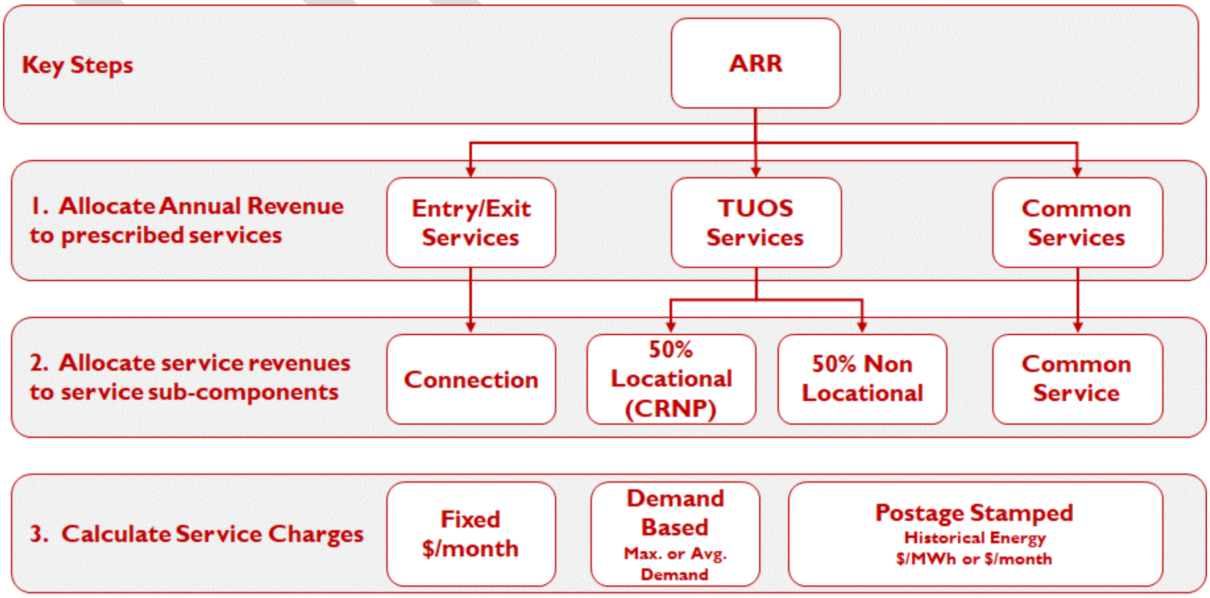
- The background to the decisions on the approach to determining revenue requirements
- Examples of different utilities required revenue calculations.

A general overview of the transmission pricing approach and concepts is given by PowerLink, the TNSP for Queensland.

Document 5-3

Title	Transmission Pricing: An Overview		
Author	PowerLink	*Date*	Aug 2015
Comment	The generic method is illustrated in Figure 3 The overview provides a useful set of definitions of key terms ○ Annual Aggregate Revenue Requirement (ARR) - the maximum allowable revenue determined by the AER adjusted by the X-factor, CPI and performance incentive schemes. ○ Common Services - provide common benefits to all customers irrespective of location (for example, voltage support). ○ Cost Reflective Network Pricing (CRNP) – a method for calculating locational prices under the Rules, based on peak utilisation of backward-looking (or sunk) asset costs. ○ Entry/Exit Services – services provided for connection to the shared transmission network. Entry services apply to generators. Exit services apply to DNSPs (distribution network service providers) and other directly connected customers supplied by the transmission network. ○ Locational charges - costs to supply TUOS services at a location within the transmission network (for example, a substation). Under the Rules, locational prices must not change by more than 2% per annum relative to the load weighted average price for the region. ○ Non-Locational charges – balance of TUOS costs that are not location-specific. ○ Long Run Marginal Cost (LRMC) – a forward-looking method for allocating network costs, where charges are based on the cost of future investments. DNSPs are required to calculate distribution charges/prices using LRMC from 2017 onwards2. ○ Postage Stamped – where the unit price is the same for all connection points and customers. ○ Transmission Use of System (TUOS) – prescribed (or regulated) services that provide benefits to customers or other TNSPs based on location. ○ X-factor – a revenue smoothing factor set by the AER to minimise price shocks.		

Figure 3: Overview of Australian Transmission Pricing (*PowerLink*)



5.1.1 APPROACH TO REVENUE DETERMINATION

The introduction of the transmission pricing regime followed a review of existing pricing mechanisms by the Australian Energy Market Commission (AEMC) followed by the development and publication of a proposed new regime by the AER. The AER's proposal was subsequently substantially implemented. The initial AEMC review and utilities' comments on the AER's initial proposal provide a useful guide to some of the issues to be considered in the design of the pricing mechanism.

Document 5-4

Title	Review of the Electricity Transmission Revenue and Pricing Rules: Revenue Requirements Issues Paper		
Author	Australian Energy Market Commission	*Date*	Oct 2005
Comment	The two themes of the review were a. Aligning the long-term incentives of transmission service providers with those of other market participants including end-use consumers b. Increasing the clarity, certainty, and transparency of the regulatory approach, Section 7 sets out issues associated with determining cost components: o Opening Asset Base. o Criteria for determining efficient investment o Operating expenditure o Depreciation o Rate of return o Tax. These issues provide a useful cross-check for any methodology adopted by ZESCO.		

Energy Australia is a large integrated gas and power company based in South Australia. As it faces similar regulation of transmission pricing in both its gas and power businesses, their review of the AER pricing mechanism provides an interesting insight into a utility's perspective of some of the issues to be considered in the design of the pricing mechanism.

Document 5-5

Title	Submission to the AER Review of Transmission Pricing Rules		
Author	Energy Australia	*Date*	August 2008
Comment	A review of the initial formulation by the AER of the transmission pricing regime. Each element of the pricing mechanism is reviewed, and any concerns identified.		

High-level issues identified included:

- The priority of objectives be established as a guide to trade-offs that may be required.
- A high degree of prescription of the method to avoid regulatory uncertainty is required.
- Should capital expenditure be assessed *ex ante* or *ex post?*
- Costs outside the utility's control should not be subject to efficiency incentives.
- Transitional arrangements for the introduction of a new regime need to be signalled in advance.

Following adoption of the pricing mechanism the AER published guidelines on its application.

Document 5-6

Title	Electricity transmission network service providers - Pricing methodology guidelines		
Author	Australian Energy Regulator	*Date*	Jul 2014
Comment	This document provides guidelines on ○ Information requirements & disclosure ○ Permitted (locational) pricing structures ○ Permitted (postage stamp) pricing structures ○ Attribution of transmission system assets to categories of prescribed transmission services ○ Inter-regional transmission charging arrangements		

Key considerations identified for pricing structures were:

Locational Pricing Structures

- Must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated
- Two approaches to determining demand may be applied:
  - The average of the transmission customer's half-hourly maximum demand recorded at a connection point on the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during the previous 12 months,
  - The contractually agreed maximum demand (prevailing at the time transmission prices are published), but this can only be used if the contract establishes liabilities for exceeding the agreed maximum
- If historical data is unavailable for a connection point, then the method of estimation must be approved.

Postage Stamp Pricing Structures

- These must be based on either:
  - contractually agreed maximum demand
  - maximum demand
  - historical energy.
- Where contractually agreed MD or historical energy is used, a customer with a load factor at its connection point equal to the median load factor for all connection points should be indifferent between the use of the energy or contract agreed MD.

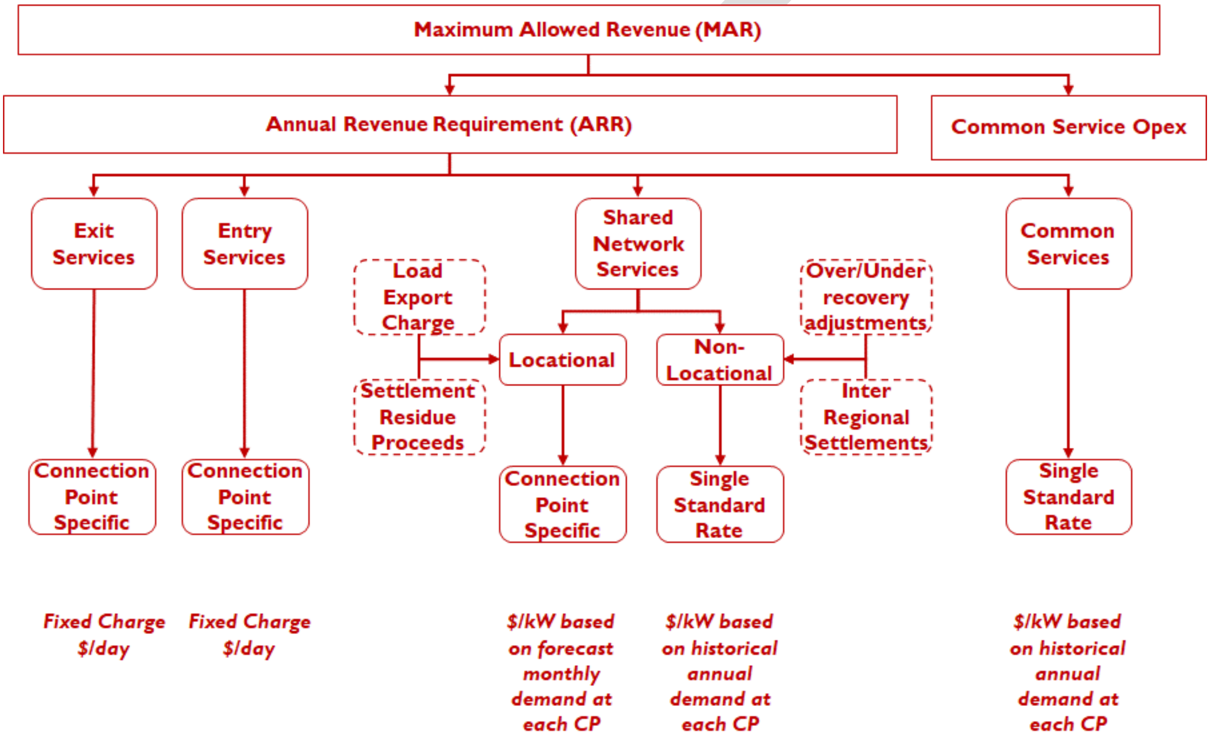
5.1.2 EXAMPLES OF UTILITY CALCULATIONS OF REGULATORY REVENUE REQUIREMENTS

TransGrid is the operator of the New South Wales transmission network. Its transmission pricing methodology has evolved over the last decade in response both to customer concerns and to changing regulatory requirements. Following these changes through the various TransGrid documents illustrated different forms of pricing and issues with them. TransGrid's current approved methodology, showing development on the basic approach in Figure 3 is illustrated below.

Table 2: TransGrid (New South Wales) Metrics

Metric	Unit	Value
Installed Capacity	MW	19 570
Peak Demand	MW	13 093
Tx lines	km	13 000 (104 substations)
Annual energy	GWh	65 800
Territory	Square km	801 150
Off-takers		3 million

Figure 4: TransGrid Approved Pricing Methodology



Document 5-7

Title	Transmission Pricing Methodology		
Author	TransGrid	*Date*	May 2014
Comment	TransGrid applied a mix of postage stamp and locational pricing methodologies. The locational pricing was established using the Cost Reflective Network Pricing (CRNP) methodology which attributes the cost of network assets to connection points based on low flow analysis using proprietary software. The paper identifies consumer concerns with the methodology and changes required to align better with regulatory requirements. Customer concerns identified were: ○ The pricing was insufficiently cost reflective ○ 50% was too high a proportion of costs to be allocated by a postage stamp methodology ○ Transmission pricing should be primarily demand rather than energy based. TransGrid modified its postage stamp and CRNP methodologies to address these concerns.		

<table>
<tr><td></td><td colspan="3">It also introduced a limit to cost increases, capping them at CPI + 3%,</td></tr>
</table>

Document 5-8

<table>
<tr><td>Title</td><td colspan="3">Framework and approach for TransGrid for regulatory control period commencing 1 July 2018</td></tr>
<tr><td>Author</td><td>Australian Energy Regulator</td><td>Date</td><td>Jul 2016</td></tr>
<tr><td>Comment</td><td colspan="3">The AER prepared this consultation paper that looks at different incentive schemes to apply to TransGrid's revenue requirement calculations. It also set out a proposed approach to determining depreciation. Three incentive schemes were proposed (their eventual application was set out in the document following):

Service Target Performance Incentive Scheme (STPIS).
This has three components:

Service – incentives for meeting key indicators of network reliability
Market Impact – incentives to minimise the impact of network outages on generation dispatch
Network Capability – incentives to undertake and promote efficient levels of network capability from existing assets.

Efficiency Benefit Sharing Scheme (EBSS)
This has the aim of providing a continuous incentive for TNSPs to pursue efficiency improvements in operating expenditure and provide for a fair sharing of these between TNSPs and network users. Consumers benefit from improved efficiencies through lower regulated prices in the future.
Capital Expenditure Sharing Scheme (CESS)
This aims to provide financial rewards for TNSPs whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower network charges in the future.
</td></tr>
</table>

Document 5-9

<table>
<tr><td>Title</td><td colspan="3">Revised Revenue Proposal to AER 2018/19 – 2022/23</td></tr>
<tr><td>Author</td><td>TransGrid</td><td>Date</td><td>Nov 2017</td></tr>
<tr><td>Comment</td><td colspan="3">This provides an example of the building blocks that make up the required revenue. It details the approach and values agreed with the regulator in respect of:

Capital expenditure
Operating expenditure
Rate of Return
Depreciation & regulatory asset base
Pass-through events

It sets out the agreed

Maximum allowed revenue under the building block approach
Pricing methodology
Application of the STPIS, EBSS and CISS incentive schemes.

It follows a standard format established by the AER for all TNSPs.</td></tr>
</table>

Document 5-10

<table>
<tr><td>Title</td><td colspan="3">Review of the TransGrid's CESS Model (appendix to TransGrid Revenue Proposal)</td></tr>
<tr><td>Author</td><td>HoustonKemp Economics</td><td>Date</td><td>Nov 2017</td></tr>
</table>

Comment	An independent review of the AER application of its CESS incentive scheme to ensure that it correctly provide for a 30 per cent sharing of the total efficiency gains and losses resulting from TransGrid's capital expenditure performance over the 2015-16 to 2017-18 period. The review concluded that the methodology did not provide the required sharing, and proposed changes necessary to meet this objective. The following methodological approaches were recommended: o The removal of any financing benefit in the year that the underspend or overspend is incurred, because a return on capital is not provided on capex within the AER's Post-tax Revenue Model (PTRM) until the start of the year following the incurring of the capital expenditure; o The financing benefit for each subsequent year incorporates the capitalisation of a ½ year WACC on capex, consistent with the approach adopted in the PTRM and roll forward model. o that the financing benefit is calculated for remaining years of the regulatory period following the capex under/overspend using the real WACC, because the PTRM delivers a real rate of return in revenues.

Document 5-11

Title	TransGrid Transmission Determination 2018-2023 Attachment B Pricing Methodology		
Author	Australian Energy Regulator	*Date*	Apr 2018
Comment	This document sets out the final approved pricing methodology. This is illustrated in Figure 4 above.		

Although governed by the same AER rules, there are never-the-less differences in approach in the revenue proposals made by ElectraNet, which is the TNSP for South Australia. This arises because each TNSP establishes its own pricing methodology so long as it:

- o Allocates the aggregate annual revenue requirement for prescribed transmission services provided by the TNSP to each category of prescribed transmission services.
- o Provides the manner and sequence of adjustments to the annual service revenue requirement.
- o Allocates the annual service revenue requirement to transmission network connection points.
- o Determines the structure and recovery of prices for each category of prescribed transmission services.

An interesting element of the ElectraNet pricing is that it has to include grand-parenting provisions for directly connected generators and customers who were connected prior to the introduction of the regulations in 2009.

Table 3: ElectraNet (South Australia) Metrics

Metric	Unit	Value
Installed Capacity	MW	6 372
Peak Demand	MW	2 955
Tx lines	km	5 600 (91 substations)
Annual energy	GWh	11 817
Territory	Square km	983,482
Off-takers		1.7 million

Document 5-12

Title	Approved Pricing Methodology 2015-2018		
Author	ElectraNet	*Date*	Feb 2015
Comment	The methodology comprises two stages: 1. Determination of the Annual Revenue Requirement 2. Allocation of Costs The allocation of costs is in four parts: 1. Allocate the costs of transmission system assets to the categories of prescribed transmission services 2. Calculation of the attributable cost shares for each category of prescribed transmission services as the ratio of: o The costs of the transmission system assets directly attributable to the provision of that category of prescribed transmission services; to o The total costs of all the TNSP's transmission system assets directly attributable to the provision of prescribed transmission services, 3. allocate the ARR to each category of prescribed transmission services in accordance with the attributable cost share for that category of prescribed transmission services. The categories are: o Exit Services o Entry Services o TUOS Services o Common Services 4. allocate the Annual Service Revenue Requirements for entry, exit and TUOS services to each transmission network connection point		

Document 5-13

Title	Revised Revenue Proposal to AER 208/19 – 2022/23		
Author	ElectraNet	*Date*	Dec 2017
Comment	This follows the same standard format as the revenue proposals of the other TNSPs. Unique elements of the ElectraNet methodology included: o An approach for accelerated depreciation of unused assets o Location specific labour cost escalation rates o Provision for additions to the opex forecasts arising from market rule changes		

The pricing methodology of TasNetworks, the TNSP for Tasmania as approved by the AER follows the same principles as all Australian TNSP's but again demonstrates the scope for slightly different approaches within the established rules.

Table 4: TasNetworks (Tasmania) Metrics

Metric	Unit	Value
Installed Capacity	MW	3 187
Peak Demand	MW	1 964
Tx lines	km	3 500 (49 substations)
Annual energy	GWh	10 038
Territory	Square km	68 400
Off-takers		520 000 users

Document 5-14

Title	Transmission Pricing Methodology 2019 – 2024		
Author	TasNetworks	*Date*	
Comment	Unique elements of the TasNetwork pricing methodology include: ○ The calculation of the locational component of prescribed TUOS services costs using a modified cost reflective network pricing methodology. ○ locational prescribed TUOS services price being based on contractually agreed maximum demand. ○ the postage-stamp basis of pricing structures for the non-locational component of TUOS services and common transmission services being based on either contractually agreed maximum demand or historical energy.		

5.2 NEW ZEALAND

The New Zealand electricity market is governed by a detailed code covering all aspects of market operations. It does not address transmission owner costs but does deal with the determination of revenue for services provided by the system operator which entail procurement from third-party suppliers, such as ancillary services purchased from generators.

Document 5-15

Title	New Zealand Electricity Code: Chapter 8 Common Quality		
Author	New Zealand Electricity Commission	*Date*	Current
Comment	The Code establishes the services to be provided by the System Operator to maintain quality (i.e. ancillary services), the rules by which the SO can procure services that are required, such as voltage support, and the process for forecasting costs to establish prices to be charged to market participants.		

New Zealand has a single transmission company, Transpower, which also acts as system operator. Transpower's revenue requirements are subject to economic regulation by the Commerce Commission, which sets a maximum allowable revenue (MAR), while its pricing structure is subject to regulation by the Electricity Commission.

Table 5: Transpower (New Zealand) Metrics

Metric	Unit	Value
Installed Capacity	MW	9 432
Peak Demand	MW	6 700
Tx lines	Km	11 200 (174 substations)
Annual energy	GWh	38 800
Territory	Square km	268,021
Off-takers		2 108 000 users

The Commerce Commission establishes the regulatory framework called the Individual Price-Quality Path (IPP), which:

- governs Transpower's expenditure allowances and allowable revenues

- provides for recovery of certain costs outside of Transpower's control
- governs approval, timing, outputs, and cost recovery for major capital projects
- sets and monitors quality targets for Transpower's transmission services.

Transpower was required to propose a transmission pricing structure to recover its allowed revenue based on some high-level guidelines set by the Commission.

New Zealand operates a full nodal marginally priced market. There is no need for separate TUOS charges as Transpower collects the rental arising from marginal pricing.

Document 5-16

Title	Transmission Pricing Methodology Guidelines for Transpower		
Author	Electricity Commission	*Date*	Mar 2006
Comment	The Commission set the following guidelines for Transpower's pricing: ○ A definition of deep connection should be developed and applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent practicable. ○ The costs of connection assets are to be recovered from those connected to them. ○ Where parties share the use of connection assets then the costs should be allocated among them on a peak demand or injection basis, in a manner that maximises efficiency. ○ Charges for existing and new interconnection assets should be on a postage stamp basis. ○ Transitional arrangements should be proposed where revision of the methodology leads to large increases or decreases in current charges.		

Document 5-17

Title	Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path		
Author	Commerce Commission	*Date*	Jul 2019
Comment	An example of a regulatory WACC determination.		

Document 5-18

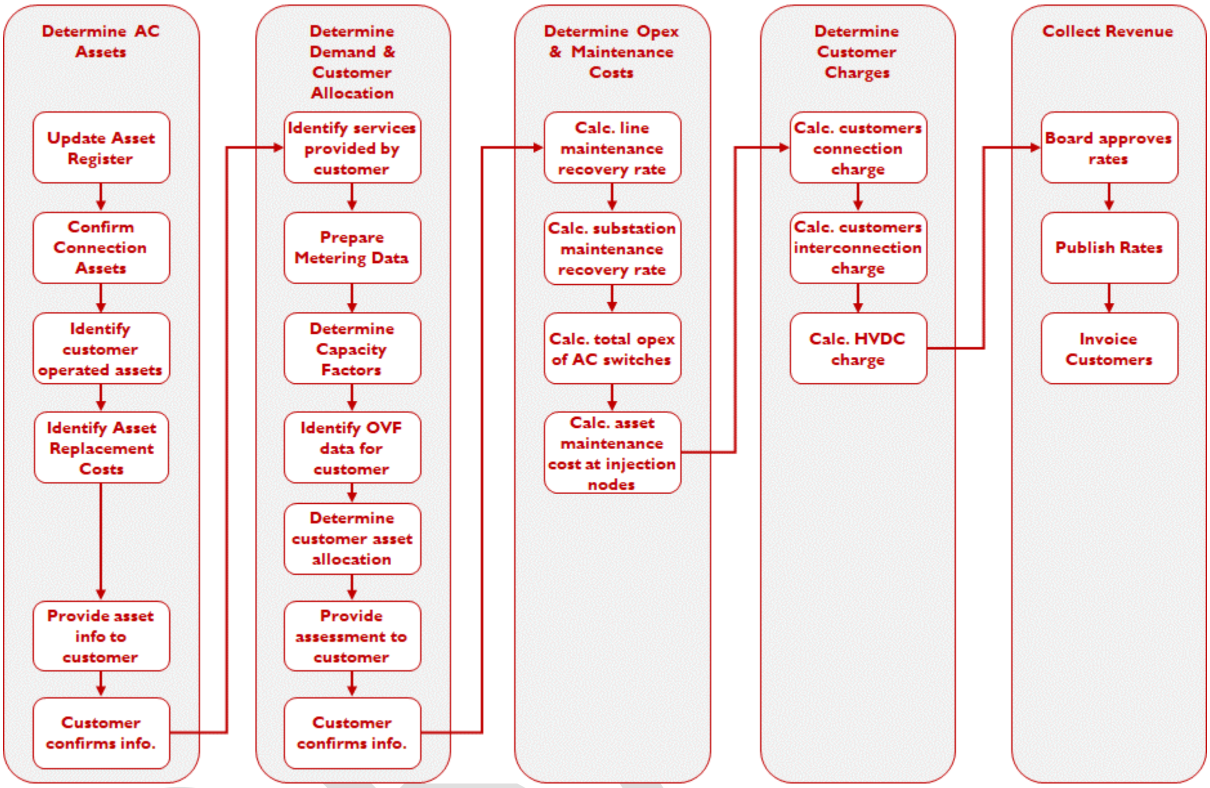
Title	Annual Regulatory Report 2011-12		
Author	Transpower	*Date*	2012
Comment	This report tracks the process of setting the MAR, starting from a forecast capex and opex expenditure, setting charges based thereon, then a MAR wash-up to adjust for actual expenditure and actual revenues received. The regulatory asset base that determines the MAR is established on a building block basis incorporating Capex, Opex, depreciation, tax and pass-through costs.		

Document 5-19

Title	Transmission Pricing Methodology Impact Assessment		
Author	PWC	*Date*	Dec 2012
Comment	Transpower's transmission pricing methodology is to allocate its MAR to customers through three charges: ○ Connection Charge to recover the cost of AC assets that connect the customer to		

	the grid. o HVDC Charge to recover the cost of the DC link between the North and South Islands. o Interconnection Charge to recover any remaining costs. The methodology is illustrated below

Figure 5: Transpower's Pricing Methodology



The reference to OVF in Figure 5 is to the Offer Volume Forecast, which collates data for the anytime maximum demand, anytime maximum injection, regional coincident peak demand and historical maximum injection.

5.3 UNITED STATES

As part of the support for the ERB's development of open access arrangements for Zambia, information on different elements of open access by three market operators, Arizona, PJM and MISO, was presented to the ERB. Most of these presentations dealt with non-pricing aspects of open access and are listed in section 5.3.4 below. While the different market regions in the United States exhibit a range of differing pricing mechanisms, transmission pricing was dealt with in a presentation by MISO and so the focus in this review has been on that organisation.

A general description of the United States' power sector and cost allocation by utilities has recently been published (*Document 5-20*). This provides a general overview to power system cost allocation in the context of economic regulation. It describes in some detail different approaches to carrying out cost of service studies.

Document 5-20

Title	2020-01 Electric cost allocation for a new era: A manual.		
Author	Regulatory Assistance Project	*Date*	Jan 2020
Comment	The focus of the document is the allocation of costs to different types of off-take customer -residential, commercial, industrial, and municipal.		

5.3.1 FERC TRANSMISSION PRICING POLICY

The US Federal Energy Regulatory Commission (FERC) has established a general policy for the approval of transmission pricing by TNSPs.

Document 5-21

Title	Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement (FR Doc No: 94-27091)		
Author	FERC	*Date*	Oct 1994
Comment	The policy statement identifies the principles by which the regulator will assess pricing approaches ("*just and reasonable and not unduly discriminatory*"), and gives examples of acceptable pricing methodologies, while stressing that there is no prohibition against any pricing approach that meets the principles. The examples of acceptable methodologies are postage stamp, contract path, MW-mile, zonal pricing based on flows between zones, flow-based line-by-line rates, or combinations of them.		

5.3.2 MIDCONTINENT INDEPENDENT SYSTEM OPERATOR

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit system and market operator for transmission networks in fifteen U.S. states and the Canadian province of Manitoba. MISO is not a TNSP but rather operates the transmission systems owned by several different TNSPs. Its collected revenues are thus allocated to its constituent TNSPs, and it serves as an example of how SAPP wheeling charges could be structured.

Table 6: MISO Metrics

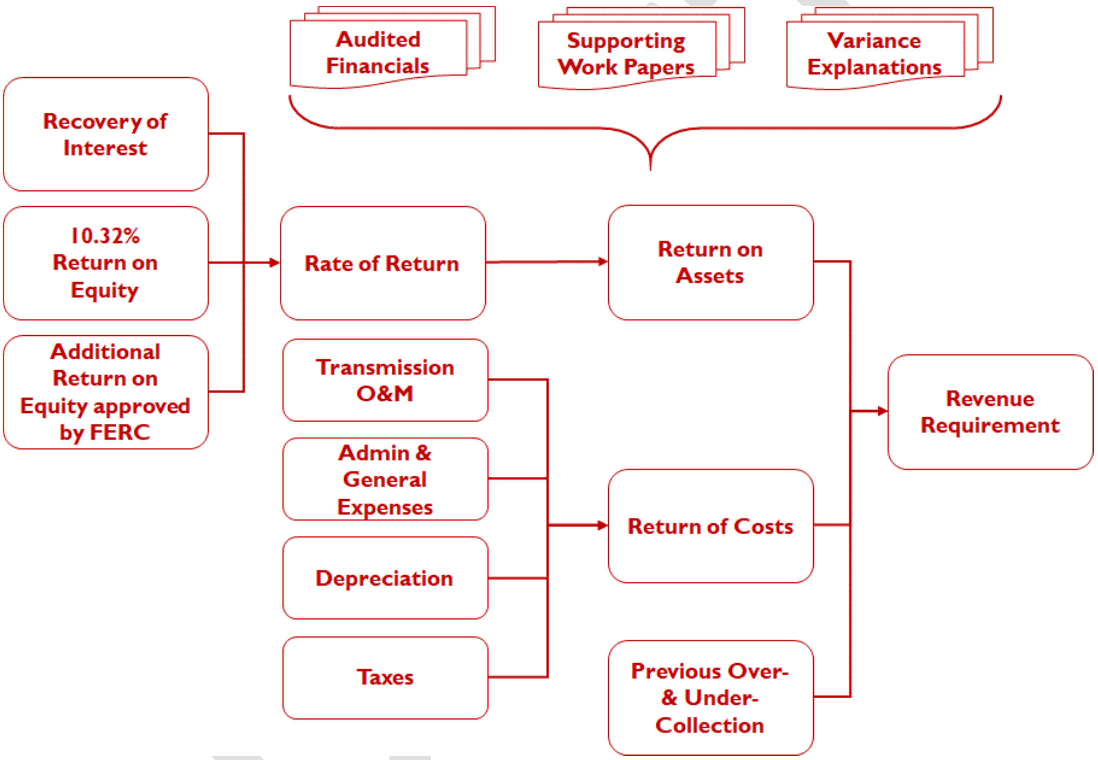
Metric	Unit	Value
Installed Capacity	MW	178 000
Peak Demand	MW	129 000
Tx lines	km	115 550
Annual energy	GWh	806 550
Territory	Square km	n/a (15 US States + Manitoba)
Off-takers		472 market participants 42 million users

Document 5-22

Title	Open Access Pricing for Transmission (Presentation to ERB) Linked to two on-line documents on the MISO website: ○ Level 100 – Transmission Pricing: Attachment O ○ Level 100 – Transmission Settlements		
Author	NARUC (MISO)	*Date*	May 2019
Comment	The presentation described the elements making up the required revenue, and the different types of TUOS (wheeling) services identified in the MISO. These are described below		

Determination of the revenue requirement in MISO is similar to other jurisdictions. An interesting feature is the regulated return on equity set at 10.32%.

Figure 6: Required Revenue Calculation for TNSPs in MISO



MISO's charges to users are a combination of:

- TUOS charges
- Network service charge, an annual charge based on a flat rate per peak demand
- Network Upgrade Charge – to recover costs of network expansion, on a postage stamp basis.

MISO differentiates between firm and non-firm TUOS charges. The charges are further split to identify the different combinations of locations for entry and exit points:

- Generation external to MISO but off-take within MISO ("drive-in")
- Both generation and off-take within MISO ("drive-within")
- Generation within but off-take external to MISO ("drive-out"
- Both generation and off-take external to MISO ("drive-through").

The rate approach and rate allocations to different TNSPs within MISO for these services are as shown in the table below. Rates differ depending on the time period over which capacity is reserved: Annual, Monthly, Peak Daily, Off-peak Daily.

Table 7: MISO Point-to-Point TUOS Structure

Type	Determining features	Allocation of revenue to TNSPs
Drive-in & Drive-within	○ Zonal rates ○ Reserved capacity ○ Dependent on duration	50% based on transmission investment 50% based on Participation Factors
Drive-out & Drive-through	○ System-wide rate ○ Reserved Capacity ○ Dependent on duration	

Document 5-23

Title	Transmission Access and Planning –Drivers for New Transmission (Presentation to ERB)		
Author	NARUC (MISO)	*Date*	May 2019
Comment	Although the transmission planning approach does not directly feed into transmission pricing, the categorisation of benefits in terms of improvements to: ○ Reliability ○ Dispatch ○ Frequency regulation ○ Spinning reserves ○ vRES integration ○ Compliance ○ Generator availability ○ Demand response. ○ Cost reduction.		

Transmission Costs for connecting new generation are discussed in a presentation dealing with transmission connection.

Document 5-24

Title	MISO Interconnection Process (Presentation to ERB)		
Author	NARUC (MISO)	*Date*	May 2019
Comment	Of interest here is the allocation of costs for required network reinforcements (see below)		

Cost allocation to generators is dependent on the reasons for the transmission upgrade.

- Network Upgrades – a pro rata share of the MW contribution on all constraints from the project
- Shared Network Upgrades - Cost allocated based on a pro rata share of MW contribution of all projects contributing to the upgrade
- Thermal Upgrades - Cost allocation based on a pro rata share of MW contribution of all project contributing to the constrained facility. MW Impact = Distribution Factor * Gen Output

- Voltage Upgrades - Allocated based on net MW Impact of each project on bus with worst voltage violation
- Stability Upgrades - Allocation based on which projects cause the instability.

5.3.3 PJM INTERCONNECTION

PJM Interconnection is a regional transmission organization responsible for system operations and the wholesale market in **P**ennsylvania, New **J**ersey, **M**aryland, Delaware, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, Virginia, West Virginia and the District of Columbia. It is also responsible for long-term planning to identify the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis.

Table 8: PJM Metrics

Metric	Unit	Value
Installed Capacity	MW	180 086
Peak Demand	MW	169 492
Tx lines	Km	135 565
Annual energy	GWh	806 550
Territory	Square km	960
Users		1018 market participants 65 million users

Document 5-25

Title	PJM Role of the System Operator (presentation to ERB)		
Author	NARUC	*Date*	May 2019
Comment	The presentation notes a fundamental question to be answered in determining transmission expansion plans and how costs should be allocated: o Should transmission be a universal right extending to remote areas, with such costs being socialised over the whole system, or should costs be allocated to specific areas benefitting?		

Document 5-26

Title	PJM Transmission Tariff		
Author	PJM	*Date*	current
Comment	This is the legal document that sets out PJM's tariffs, which are broken into: o Common services o Point-to-point services o Network Integration services o Interconnection Attachments set out the form of contracts for these services.		

PJM uses nodal marginal pricing to set prices for energy purchases and sales in the PJM market and to price transmission congestion costs. PJM"s shared network costs are recovered only from loads, through two charges:

- Load-based access charges levied on loads according to load coincident with peak annual zone demand (i.e. pro-rated according to use at coincident peak annual demand).
- Usage charges due to differences between nodal prices due to congestion and losses. These costs can be hedged via the use of financial transmission rights.

Because PJM is not the owner of the transmission systems it operates, it is not responsible for determining the transmission costs that are included in the network integration services.

5.3.4 OTHER OPEN ACCESS PRESENTATIONS TO THE ERB

The following documents were also presented to the ERB by NARUC as part of its work on open access pricing. While they do not deal directly with transmission pricing, they inform decisions on open access arrangements that the transmission pricing regime must support.

Document 5-27

Title	The Evolution of Open Access and Electricity Competition in the United States: Looking Back to Look Forward		
Author	NARUC (PJM)	*Date*	May 2019
Comment	The presentation concludes with five "lessons learned" that bear repeating as they equally apply to the development of transmission pricing: 1. Market establishment is a complex challenge, with high stakes. Electricity market establishment programs are large, high-profile, multi-disciplinary undertakings, critical to the overall market reform agenda. 2. Scope is a moving target. Often processes are being defined, and systems specified, while the market design and rules are still being finalised. This is a frequently unavoidable reality, that must be carefully managed. 3. Capability involves more than just systems. Establishing the market involves not just complex IT, but significant organizational change and process development.: 4. Provide a soft landing Where participants are unfamiliar with market constructs, they face substantial commercial risk at market opening. Constructs such as 'vesting' contracts are essential in managing this 5. Lack of participant readiness is a frequent cause of market delay It is essential to involve participants early in the market establishment process, and frequently assess their readiness to ensure they are commercially prepared:		

Document 5-28

Title	Arizona Line-Siting Process		
Author	NARUC	*Date*	May 2019
Comment	The key considerations in line siting identified are: ○ Fit with existing plans in the vicinity ○ Environmental impact. ○ Estimated cost and the impact it may have on customers ○ Noise emission levels ○ Previous experience – technical expertise		

Document 5-29

Title	Arizona Renewable Energy Integration		
Author	NARUC	*Date*	May 2019
Comment	The Arizona use of markets to provide balancing services for renewables is not (yet) applicable to the market structure in Zambia.		

Document 5-30

Title	Regulating Service Quality Standards		
Author	NARUC (Arizona Attorney General's Office)	*Date*	May 2019
Comment	A brief overview of system reliability and its measurement metrics: ○ Frequency of outages (SAIFI) ○ Average duration of outages (SAIDI) ○ Length of outages experienced by customers (CAIDI) ○ Momentary average interruptions (MAIFI) ○ Number of customers affected by outages		

5.4 United Kingdom

The System Operator in the UK electricity system is currently part of National Grid Electricity Transmission, (NGET). The electricity market is regulated by the Office of Gas and Electricity Markets (Ofgem).

Table 9: NGET (UK) Metrics

Metric	Unit	Value
Installed Capacity	MW	82 932
Peak Demand	MW	50 412
Tx lines	km	7210 347 substations
Annual energy	GWh	300 000
Territory	Square km	78 700
Off-takers		n/a

Ofgem has historically regulated the SO as part of NGET but has indicated that it intends moving to separate the regulatory structures for the transmission and SO roles. It has published a discussion paper looking at approaches to regulating the SO function.

Document 5-31

Title	Review of potential models for the regulation and remuneration of the electricity system operator		
Author	REKON, for Ofgem	*Date*	Jun 2018
Comment	The paper is concerned with the overall regulation of the SO and identified four approaches needed to achieve the outcomes desired from the regulation: ○ Supervision of the SO behaviour ○ Exposure of the SO's services to competitive and customer pressure		

	o Use of regulatory financial incentive arrangements o Supervision of SO's performance and charges. The approach to pricing was based on a differentiation between 'internal' costs, that is, the SO's own costs for equipment, staffing, etc. and "external' costs, being payments for ancillary and balancing services. Differing approaches were considered, including: o regulation of internal costs, with external costs treated as pass-through. o all costs being treated as pass-through. o all costs subject to a regulated revenue approach. o price controls on each individual service (the paper established a long list of separated services provided by the SO).

6. ACADEMIC PAPERS

Academic papers are categorized in two ways:

- General transmission pricing considerations.
- Technical papers in support of the SAPP pricing methodology.

6.1 General Papers

Document 6-1

Title	Transmission Pricing and Renewables - Issues, Options and Recommendations		
Author	Stoft, Webber & Wiser (UC, Berkeley)	*Date*	May 1977
Comment	A discussion of how vRES generators may be differentially affected by the transmission pricing structure and arguing in favour of energy-based rather than capacity-based charging: o Capacity-based charges needlessly penalize low-capacity-factor intermittent generators; energy-based charges do not. o In a competitive market, capacity charges can interfere with congestion prices, while energy-based charges do not. o Under the neutral assumption of uniform demand elasticity, an energy-based charge causes less distortion in consumption patterns than a capacity-based charge.		

Document 6-2

Title	Transmission Pricing Issues & International Experience		
Author	Bodenhofer & Wohlgenuth (University of Klagefurth)	*Date*	2001
Comment	While the review of then current regulations in the US and Europe is now out-of-date, the paper presents a nice overview of the different approaches to TUOS charging, categorised in terms of: o Point charging: based on the energy injected or withdrawn in each node in isolation (postage stamp, nodal pricing, zonal pricing). o Point-to-point charging: based on the source and sink of each individual transaction (contract path, distance-related)		

Document 6-3

Title	2013-10 Overview of Tx Pricing Methods		
Author	Murali, Kumari & Sydulu (JSET vol1)	*Date*	Oct 2013
Comment	The paper provides a useful example of calculations to compare different methods of transactional pricing applied to the same network. The general categorisation of pricing methodologies is shown in Figure 8 below.		

Document 6-4

Title	Assessing the Cost Reflectivity of Alternative TUOS Methodologies		
Author	NERA Economic Consulting	*Date*	Feb 2014
Comment	The paper presents the results of an analysis using a dynamic investment transmission model to estimate the LRMCs of transmission associated with different generation technologies. Although the results are specific to the UK system, and focus on wind, the paper provides a good introduction to the use of LRMC to benchmark different transmission pricing		

	methodologies. It argues in favour of locational marginal pricing as the ideal pricing mechanism.

6.2 Technical Papers Supporting SAPP Pricing

Document 6-5

Title	Variation of Distribution Factors with Loading		
Author	Ross Baldick (University of Texas)	*Date*	Aug 2003
Comment	Power transfer distribution factors (PTDF) depend on the operating point and topology of a power system. The paper demonstrates that, for a fixed topology, the PTDFs are relatively insensitive to the operating point. The maths is interesting but the paper is only relevant in that it supports the assumptions in the SAPP pricing model.		

Document 6-6

Title	2015-03 Marginal Pricing of Tx Services using Min-Max fairness		
Author	Rao & Soman - IEEE TPS vol30	*Date*	March 2015
Comment	A min-max fair nodal tariff solution is one in which a reduction in the tariff of an entity (load or generator) can occur only at the cost of another entity which pays equal or higher nodal tariff. An algorithm is developed to determine a fair allocation of costs between generation and load nodes. This is adapted in the SAPP pricing model.		

Not reviewed: Bialek,J. *Tracing the flow of electricity, Generation, Transmission and Distribution*, IEE Proceedings, vol 143, no 4 pp 313,320 Jul 1996

7. APPLICATION TO ZAMBIAN TRANSMISSION PRICING

7.1 Transmission Owner and System Operator

The Zambian legislation (*Document 2-1*) and Grid Code (*Document 2-2*) differentiate between the Transmission Network Service Provider (TNSP) and the System Operator. Separate licences and pricing arrangements are therefore required for each entity.

The requirements of a TNSP are defined as:

- To develop, maintain and operate a transmission network and (where applicable), transmission network interconnections with other networks.
- To determine the terms and conditions for the provision of transmission services to transmission network service users in a non-discriminatory and cost reflective manner.
- To comply with the Act, their licence, and the grid code.

The requirements for the system operator are defined as:

- To operate a transmission network and its inter-connectors with other networks in order to guarantee the security of supply of electricity.
- To manage energy flows on the transmission network and maintain a balance of the energy flow.
- To ensure the availability of the necessary ancillary services for the generation of electricity.
- To provide sufficient information to other transmission regional operators on an interconnected system to ensure secure and efficient operation.
- To ensure a coordinated development of the interconnected system.
- To ensure non-discrimination between system users or classes of system users.
- To provide a system user with the information needed for efficient access to the transmission system or distribution system, dispatching of electricity and determining the use of inter-connectors.

It may be observed that the objective in operating the system is only described in terms of maintaining security of supply. The only reference to any efficiency requirement is in terms of interconnection. There is no economic efficiency objective established.

The review of possible SO regulation conducted for Ofgem (*Document 5-31*) concluded "*there is unlikely to be a good off-the-shelf regulatory model that we can take from ESO regulation in another country, or from another UK regulated sector*".

7.1.1 TARIFF PRINCIPLES

The Zambian Electricity Act (*Document 2-1*) establishes the following principles for determining tariffs to consumers, which may be considered as reasonable principles to apply to transmission pricing as well:

a) A tariff shall be fair and reasonable and reflect the cost of efficient business operation.

b) A tariff shall ensure quality of service, predictability of tariff adjustment and reasonable rate of return on capital investment.

c) A tariff shall encourage competition, economical use of the source of the electricity, good performance and optimum investment.

d) A tariff shall reward efficiency in performance.

e) A tariff shall reflect enforceable standards for the quality and cost of the supply of electricity to retail consumers and non-retail consumers.

The Electricity Act (*Document 2-1*) also provides some guidance as to the allocation of costs for upgrading the grid to users causing the need for upgrades:

> *"An applicant shall be granted access to a transmission network … on the conditions … including contributions towards the upgrading by the potential network user of the network, if applicable"*

The draft open access regulations (*Document 2-5*) envisage a use-of-system charge in the form of a postage stamp (Zambian currency) rate per kWh, while the ERB's discussion paper on wheeling (*Document 2-4*) envisages a MW-km pricing regime. While these provide guidance, it would appear that there is, as yet, no formal transmission pricing methodology established for ZESCO.

7.2 UTILITY TRANSMISSION PRICING

While transmission pricing approaches/methodologies differ to varying degrees in their applications, at a fundamental level, they follow the same process (Deloitte on USA, *Document 4-1*, West Africa *Document 4-10*; Malawi (proposed) *Document 4-9*; Australia, *Document 5-3*; New Zealand *Document 5-18*). The generic process is applicable to both transmission asset owners and system operators (MISO *Document 5-22*).

Figure 7: Steps in Transmission Pricing

These four stages are further discussed below.

7.2.1 DETERMINATION OF ANNUAL REVENUE REQUIREMENT

Although determination of an annual revenue requirement is most common, in some jurisdictions the revenue requirement at the aggregate level is not estimated. Instead, the key transmission services are first identified, and the revenue required for each service determined individually. This is typically the case where revenue requirements are based on estimated purchase costs, such as for system operator recovery of ancillary service costs (for instance, New Zealand *Document 5-15*).

The Annual Revenue Requirement for a TNSP, for each year of a regulatory period, is most commonly determined by using the so-called building block approach, as preferred by the ERB (*Document 2-4*)[5].

The key additive building blocks are:

- Regulatory asset base
- Return on the regulatory asset base

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[5] Although it has fallen out of favour due to the considerable difficulties of comparing like-for-like, and alternative approach (not reviewed here) is to benchmark costs against some international standard.

- Depreciation of the asset base.
- Operating expenditure.
- Estimated tax payments.
- Estimated pass-through costs.

These building blocks are first estimated for the first year of the regulatory period. Then they are rolled over to the remaining years. A regulatory incentive to improve efficiency may be applied either in the form of a rate of return adjustment, or as a CPI-x adjustment (Australia, *Document 5-2*).

Regulatory Asset Base

The regulatory asset base will be estimated by determining the valuation of each asset in the transmission system, with the use of an approved valuation method. SAPP has allocated values based on the replacement cost for wheeling assets (*Document 3-4*), including those in Zambia. For consistency, the same values will ideally be used in the domestic pricing calculations.

The methodology must also establish the criteria for future investment decisions so that these can be incorporated into the asset base. These are typically economic criteria (AER, *Document 5-4*), but there are also social imperatives such as the need for electrification of remote areas (PJM, *Document 5-25*).

The Zambia Grid Code (*Document 2-2*) establishes the following criteria for ZESCO:

> *Network Chapter 6.3.6 Least economic cost criteria*
>
> *When investments are made in terms of improved supply reliability or quality, this would be the preferred method to use. This methodology should also be used to determine or verify the desired level of network or equipment redundancy. The methodology requires that the cost of poor network services needs to be determined. These include the cost of interruptions, load shedding, network constraints, poor quality of supply, etc. Statistical analysis of network outages is also required.*
>
> *The least-cost investment criterion equation to be satisfied can be expressed as follows:*
>
> *Value of improved QOS to end-use customers > Cost to the service provider to provide improved QOS*
>
> *From the equation above it is evident that if the value of the improved QOS to the distributor or end-use customer is less than the cost to the service provider, then the service provider should not invest in the proposed project(s).*
>
> *Equation above can be stated differently as:*
>
> *Annual value (US$/kWh) x Reduction in EENS to consumers (kWh) > Annual cost to the service provider to reduce EENS (US$)*
>
> *The reduction in EENS is calculated on a probabilistic basis based on the improvements derived from the investments*
>
> *The cost of unserved energy is a function of the type of load, the duration and frequency of the interruptions, the time of the day they occur, whether notice is given of the impending interruption, the indirect damage caused, the start-up costs incurred by the consumers, the availability of end-use customer back-up generation and many other factors.*

Return on Capital

The return on capital is usually estimated by calculating the weighted average cost of capital (WACC).

The generally accepted method for calculating the weighted average cost of capital is shown below.

WACC = (Debt capital / Total capital) * Cost of debt + (Equity capital / Total capital) * Cost of equity

The timing of application of the return on new capital investment determines whether the TNSP is affected by any under- or over-spend (*Document 5-10*).

Adjustments to the WACC are used in Australia for establishing various incentive schemes (*Document 5-10*), but the introduction of such schemes to Zambia could only be contemplated after a basic pricing methodology.

The determination of the WACC may be a matter for negotiation between the TNSP and the regulator (TransGrid, *Document 5-9*) or the subject of detailed independent evaluation commissioned by the regulator (New Zealand, *Document 5-17*).

Depreciation

For estimating depreciation costs, assets are grouped into different categories. Economic lives are assigned to different asset categories. The total depreciation is then calculated based on the estimated valuation of all assets in each category and their assigned economic lives.

The treatment of unused assets must be established (ElectraNet, *Document 5-13*).

Operating Expenditure

The TNSP needs to prepare the forecast of operating expenditure, which will meet the following requirements:

- Manage the expected demand for the transmission services.
- Maintain the expected/prescribed quality, reliability, and security of supply.
- Maintain the safety of the transmission system.

In an evolving market, provision may need to be made for unforeseen costs due to market design changes (*Document 5-13*).

For the system operator, much of its expenditure may be related to the contractual procurement of ancillary services, where the budget expenditure can be based on contractual costs (e.g. South Africa *Document 4-8*, New Zealand *Document 5-15*)

Estimated Tax Payment

The TSP needs to estimate the tax payment in accordance with the accepted accounting practices.

Tax is not always separated from operating expenditure (TransGrid, *Document 5-9*).

TNSP Pass-through Costs

Pass-through costs for extraordinary events need to be determined, either estimated in advance (possibly through benchmarking), or recovered post facto. Extraordinary events for a TNSP are those that cannot be anticipated but are required to deliver the key transmission services to the required quality, reliability, and security, in the interest of the customers.

Rollover of the Building Blocks

The TNSP needs to estimate the building block items for the subsequent years of the regulatory period. This requires an established process for identifying and planning future investment.

The Zambian Grid Code (*Document 2-2*) establishes a five-year-ahead planning cycle.

7.2.2 IDENTIFICATION OF KEY TRANSMISSION SERVICES

In general (PowerLink, *Document 5-3*, TransGrid, *Document 5-7*), the following are the key transmission services:

- Connection Services (for generators and loads), sometimes treated separately as:
  - Entry services (for generators).
  - Exit services (for loads).
- Shared network services (for all generators and loads).

For connection services, the allocation of deep and shallow connection costs must also be determined (Tranpower, *Document 5-16*).

7.2.3 ALLOCATION OF REVENUE REQUIREMENT TO TRANSMISSION SERVICES

The commonly accepted method for allocating the aggregate revenue requirement to the key transmission services is to allocate the total revenue in proportion to the asset values of the three transmission services. In other words,

- Revenue allocation to entry services = Annual revenue * (Asset value of entry services / Total system asset value)
- Revenue allocated to exit services = Annual revenue * (Asset value of exit services / Total system asset value)
- Revenue allocated to shared network services = Annual revenue * (Asset value of shared network / Total system asset value).

7.2.4 ALLOCATION OF SERVICE RR TO INDIVIDUAL CUSTOMERS

The revenue requirement from entry and exit services is allocated to the various customers (for that service) in proportion to their asset values.

For the Shared Network Services, the first step is to allocate the required revenue into locational and non-locational components. This may be done on a 50:50 basis (South Africa *Document 4-8*, Australia *Document 5-3*) or costs recovered from loads only (PJM, *Document 5-26*).

The non-locational component is typically allocated to the entry and exit customers on a postage-stamp basis (South Africa *Document 4-8*, Australia *Document 5-3*, New Zealand *Document 5-16*). This approach also typically applies to network upgrade costs where network upgrade costs are separated from required revenue (MISO *Document 5-22*, New Zealand *Document 5-16*).

The locational component revenue is allocated for each month on the basis of demand rather than energy (TransGrid *Document 5-7*) in proportion to the maximum demand (MW for generators, kVA for loads) of that customer for that month.

7.2.5 VARIANT APPROACHES

For connection services, in New Zealand (*Document 5-19*) rather than establishing an aggregate revenue allocation, assets used for servicing each customer (generator and load) are identified. The revenue requirement for servicing each customer is determined using the building block approach discussed in section 7.2.1 above.

There are various methods for the valuation of assets used for the shared network services (defined as those that are not identified as connection assets). These may be based on historical costs (South Africa *Document 4-8*), the costs associated with an optimised grid (New Zealand *Document 5-16*) or may be identified with valuations based on fixed values for different equipment types agreed with the regulator (SAPP, *Document 3-4*). Then, the total revenue requirement for this service category is determined using the building block approach. Shared services may then be allocated either in aggregate, or further broken down to reflect location.

Aggregate Allocation of Shared Service Revenue Requirement

The next step is to allocate this total revenue to all load customers based on the postage-stamp method. For a given load customer, this is calculated by multiplying the total revenue by the load's Regional Coincident Peak Demand (RCPD) and then dividing it by the sum of all loads' Regional Coincident Peak Demand.

Disaggregated Allocation of Shared Service Revenue Requirement

The total revenue requirement may be allocated to locational and non-locational components.

The locational component is estimated by calculating the long run marginal cost (LRMC) of the shared network at multiple nodes. These LRMC estimates at the various nodes are then aggregated into generation and demand zones.

Having calculated the locational revenue, the remainder of the revenue requirement for shared networks is labelled as non-locational or residual revenue.

The locational and non-locational components of the shared network revenue are then allocated to the generators based on their maximum installed capacity and for loads based on their load when the system demand is at its highest.

7.3 TUOS (WHEELING) CHARGING

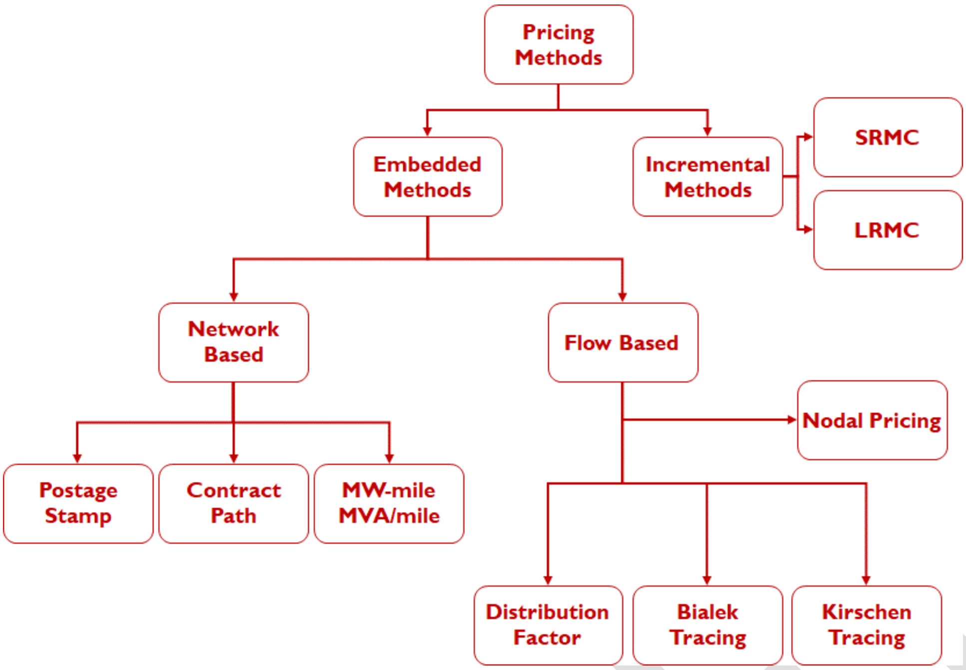
7.3.1 TYPES OF WHEELING CHARGES

Wheeling charging in any integrated network comprising jurisdictions of several electric utilities, encompasses two components:

- Revenue Requirements (RR) that establish how much each transmission network system provider (TNSP) is allowed to recover from the use by the agents of the TNSP's network; and
- Revenue Allocation (RA) mechanisms to establish the allocation of the allowed remuneration of a TNSP among users/agents of the transmission system.

The common approaches to wheeling are summarised below (Deloitte *Document 3-1*, Murali, *Document 5-16*).

Figure 8: Types of Pricing Methodologies (*after Murali et al*)



Incremental Methodologies

There are two versions of the marginal cost-based methodology, being the short and long-run versions.

The short-run marginal cost-based (SRMC) methodology includes the incremental cost for the use of the transmission system caused by a new transaction. The SRMC is estimated at all the delivery and receipt points and is usually below the average cost of the total system, which would lead to under-recovery of costs.

The LRMC methodology accounts for both the capital and operational costs by calculating the marginal capital investment plus the marginal operating costs. The key advantages of the LRMC are that it provides the correct price signals and that prices are stable and predictable under it. However, the major disadvantage is the difficulty in estimating the incremental investment costs attributable to individual wheeling transactions, when multiple transactions occur simultaneously.

Postage-stamp Methodology

The postage-stamp methodology is a simple approach to estimating wheeling charges which effectively applies a fixed charge per unit of power transmitted within a zone. The postage-stamp wheeling charges are allocated based on an average embedded system cost and the magnitude of transacted power. This is the form of charging envisaged in the draft open access regulations for Zambia.

Postage-stamp rates may include energy and capacity charges, and may vary for peak and off-peak periods, by season, and be different for weekdays and weekends.

While the key advantages of the postage-stamp method are that it is simple and easy to implement, and transparent and easily understood by market participants, the primary disadvantages are that it does not account for actual system power flows nor does it provide economic price signals to market participants.

Contract Path Methodology

The contract path method charges entities based on a pre-defined path of power flow, which is usually the shortest route from the point of power uptake to the point of delivery. This method is based on the capital costs for facilities that lie along the assumed contract path, not for the network as a whole.

This method is relevant for networks that do not have multiple paths of interconnection, which is not a realistic situation because in most power system networks power flows through multiple power paths depending on network characteristics.

The key advantages of this methodology include its relative simplicity to implement and that it accounts for the distance involved in wheeling. However, the main disadvantages are:

- The contract path is decided as a priori without any simulation of actual power flows.
- The assumed power flow path is not a realistic description of how most power networks behave.
- The methodology does not provide economic signals.

MW-km Methodology

The MW-km methodology is based on charging entities that are based on the magnitude of power transacted and the distance between the source (point of delivery) and the sink (point of receipt).

The basic version (termed distance-based) of the MW-km methodology is based solely on the MW transacted and the geographical distance.

This may be enhanced through the calculation of power flows (based on power flow simulation) to identify the specific assets used between the source and sink. Two DC power flows are determined, one with wheeling and one without. A comparison of the two shows the utilisation of each component due to wheeling.

By considering the actual power flows this enhancement improves the price signalling to both short and long-distance entities.

This is the methodology proposed by the ERB (*Document 2-4*) although it is not clear whether they propose the use of power flows.

Flow-Based Pricing or Entry-Exit Pricing

Various methodologies of varying levels of complexity have been developed to determine the supply to each demand by each generator (ZESCO, *Document 3-6*). These approaches are typically used for pool structures of power markets and can also be used for bilateral trades.

Nodal Pricing

Under the flow-based pricing approach, each uptake and injection node has its own price based on locational economic signals derived from a dynamic assessment of the network flows. This approach has been implemented in New Zealand and PJM.

The key advantages are correct price signals to market participants and, therefore, increased allocative and dynamic efficiency.

The key disadvantage is the methodology's complexity that makes it more difficult to implement.

7.3.2 CURRENT SAPP WHEELING

The methodology developed by PPL had the following two parts (*Document 3-3*):

- The determination of the network costs of wheeling and revenue shares per TNSP; and
- The determination of network wheeling prices to users/agents of the TNSPs' systems.

PPL developed detailed steps for each of these.

For the first part, the following steps were undertaken:

- A transit horizontal network (THN) was defined, representing the transmission assts that could potentially be used for wheeling.
- The THN was costed for each TSO based on a standard costing methodology incorporating both assets-related and opening costs.
- A transit key (TK) was defined for each TSO as the ratio of energy that was wheeled to the total energy transported on the network.
- The TNSP's network cost of wheeling was then calculated as the product of the TK and the cost of the THN for each TSO.
- Each TNSP's share of revenue received from network charges was determined as the ratio of that TNSP's network cost of wheeling (across all TNSPs).

To determine the network prices allocated to participants, the following steps were undertaken:

- The nodal power transfer distribution factor matrix (beta-matrix) was formed, representing the incremental MW flow in each element of the network resulting from incremental injection or extraction at each node.
- Each network element was costed using standard costing factors to provide a vector of unit-network costs ($/MW per year).
- For each generator node, the relevant column of the beta-matrix was multiplied by the vector of network costs and the relevant transit key, where the costs of both network elements inside the network's host country and outside the THN are set to zero.
- In each country, a single nodal price for all generators and all loads was determined based on the arithmetic average of all nodal prices in the country.
- The resulting nodal prices ($/MW per year) were converted to energy prices ($/MWh) at an assumed load factor of 100%. The energy prices were then adjusted with an additive component so that revenue received from network charges was equal to the total network costs of wheeling across all TSOs.

PPL's methodology was implemented and remains in use. However, difficulties arose in the use of the PPL's wheeling methodology and AF Mercados was commissioned in 2013 to develop a new methodology which would be suitable for the day ahead market regime.

7.3.3 PROPOSED SAPP WHEELING – DISTRIBUTION FACTOR/BIALEK

In 2013, SAPP commissioned AF Mercados to develop a wheeling charging methodology and model which could provide a more appropriate basis for the charging regime in the day ahead market regime (*Document 3-1*).

The following objectives for the new wheeling charging approach were agreed upon:

- Promote efficient operation of the wholesale electricity market.
- Signal efficient investments in generation, load and transmission projects, including signals for efficient siting of generation projects.

- Provide adequate compensation to TNSPs.
- Be simple and transparent.
- Be politically implementable.

The last objective is important because the methodology and the associate models must be acceptable to all SAPP members.

The scope of the Mercados work included developing a methodology for activities relating to the transmission cost of wheeling. However, it did not include dispatch related costs (such as energy losses, congestion, ancillary services, and system balancing), which are to be covered in a separate dispatch methodology.

The methodology proposed by AF Mercados for transmission costs of wheeling encompasses two main components, which are:

- Revenue Requirements: This is expected to remunerate TNSPs for providing their transmission systems for wheeling. It is mainly concerned with determining what assets TSOs provide for wheeling and what are the costs associated with the use of these assets; and
- Revenue Allocation: Allocation of TNSP's remuneration among users of the transmission system.

Revenue Requirements

The methodology for determining revenue requirements for each TNSP is based on the following three elements:

- A process for identifying assets in each TNSP used for transit of power that is identical for each TNSP's assets.
- A consistent method of valuing each TNSP's assets.
- A consistent methodology to determine revenue compensation for each TNSP for providing its assets to be used.

It was decided that revenue requirement would be determined through:

- A sinking fund method for return on asset value and O&M charges as 2% of asset value.
- A discount rate (return on assets) at 8%.
- Applicable to all assets above 130 kV.

Revenue Allocation

In Mercados' work, the following criteria were used for designing revenue allocation amongst the users of the TSO's assets:

- Who should pay? Generators/traders or buyers/consumers?
- What basis should be adopted for defining the use of the TNSPs' assets:
    - Peak MW.
    - Total annual generation.
    - Total consumption.
    - Other?
- What costs should be compensated to TNSPs; and

- The method for allocating costs to the users/agents that use TNSP's assets?

AF Mercados evaluated their transmission wheeling charging methodologies using alternative methods for estimating revenue requirements and several criteria for estimating revenue allocation.

For determining the Required Revenue, Mercados used the following two methods:

- Sinking fund during the life of the asset; and
- Linear depreciation.

For Revenue Allocation, AF Mercados decided that both generators and loads should pay. They tested several criteria for the generation's use, which included:

- Peak load in (MW).
- Total annual generation (MWh).

For load/consumers' use, they tested the:

- Maximum demand (MW); and
- Total annual use (MWh).

For estimating the use of the TNSPs' assets, they modelled power flows using the following methods (*Document 3-2*):

- Marginal participation with multiple slack nodes.
- Marginal participation with one slack node.
- Average participation.

Based on their analysis, AF Mercados proposed the following transmission pricing mechanism for SAPP:

a) Instead of the concept of the "Transit Horizontal Network", inter-country compensation for use of the transmission network is proposed to be computed based on the Marginal Participation method.

b) Each generator and each demand in their inter-connected cross-country network may impact network flows in networks in the jurisdiction of other interconnected countries. The contribution of each generator and load in each network line is therefore proposed to be computed based on the Marginal Participation method, with multiple slack nodes. There were three alternatives analysed on how to establish the transactions between the multiple slack nodes and the recommended alternative is:

> *Network Utilisation is computed using the Marginal Participation Method, where 1 MW is sequentially injected (withdrawn) at various generator (load) buses and corresponding distributed amounts of power are withdrawn (injected) at various load (generator) buses identified using the Average Participation Method. (see also South Africa, Document 4-8)*

c) The network utilisation as determined above allows the computation of the extent of network utilisation in each country by each generator/demand of foreign countries.

    - This allows for the flexibility of not charging the generators/loads for network utilisation in their own country. Therefore, the TPM charge should be determined based on the network utilisation which excludes the network utilisation in the country where the generator/load is physically located.
    - The nodal charges for all generators (loads) located in a country should be aggregated

to determine the zonal (or country wide) TPM charges.

- It is assumed that the cost recovered by transactions is a percentage of each facility cost given by the relationship between the flow in each typical load flow and the facility capacity.

d) The charges computed above should be converted into charges (in $/MW) by dividing the total charges computed by injection (withdrawal) as used in the underlying load flow analysis. Since load flow analysis is carried out for a particular "snapshot" of the grid, different identified "snapshots" should be given weights based on the load duration curves (*Document 3-2*).

In general, the approach followed by the Coordination Centre was in the methodology proposed by Mercados. The following approach was proposed:

- The "use" by each participant is calculated using Marginal Participation with multiple slack nodes.
- Payments from each user calculated as the weighted average of the payments calculated for several load flows.
- For each year, assumptions will be made of peak generation and peak demand for each TNSP in SAPP.